# List of Attachments

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| Attachment A | Verified Statement of Professor J. Peter Williamson, Laurence F. Whittemore Professor of Finance, Emeritus, Amos Tuck School of Business Administration, Dartmouth College |
| Attachment B | Affidavit of Professor Adam B. Jaffe, Professor of Economics, Brandeis University |

**Verified Statement of**
**Professor J. Peter Williamson**
**On behalf of**
**Vastar Resources, Inc.**

**Introduction**

I am J. Peter Williamson, the Laurence F. Whittemore Professor of Finance, Emeritus, of the Amos Tuck School of Business Administration, Dartmouth College, Hanover, New Hampshire. My business address is 89 Main Street, West Lebanon, NH 03784, P.O. Box 5160, Hanover, NH 03755. My qualifications appear in Exhibit No.1 to this statement.

The purpose of my verified statement is to discuss two aspects of the comments of Vastar Resources, Inc. ("VRI") on the new rules proposed by the Minerals Management Service ("MMS") in the "Further Supplemental Proposed Rule Establishing Oil Value for Royalty Due on Federal Leases." Those two aspects have to do with the calculation of the wellhead value to which a royalty percentage is applied, and more specifically to the determination of the cost of transportation of the oil from the wellhead to the point at which a market price for the oil can be established.

My understanding is that the MMS has regulations that govern the calculation of the royalties on oil produced on federal lands. In certain circumstances (such as offshore production), those regulations require a so-called "netback" calculation, in which the royalty valuation at the wellhead is determined with reference to a market price downstream of the well. From that market price, the cost of transportation must be deducted to obtain a wellhead value to which the royalty percentage is applied. Where the relationship between the oil producer and the pipeline transporting the oil is at arm's length, I understand that the MMS will typically utilize the pipeline's stated tariff or contract rate as the transportation cost for purposes of the netback calculation. However, where the producer and the pipeline are not at arm's length (i.e., they are affiliated), the MMS will frequently impute a transportation cost, one that may be different from the pipeline's stated tariff or contract rate, based on the cost factors defined in the MMS regulations.

VRI's position in its rulemaking comments, as I understand it, is that the MMS should utilize the stated tariff or contract rate for transportation, even in non-arm's length transactions, where there is a reliable, independent benchmark confirming that the stated rate is reasonable, such as rates charged in arm's length situations by other owners of the same pipeline or rates charged by a prior owner to unrelated third parties. However, if the MMS determines nonetheless to apply a methodology designed to impute a transportation cost for affiliated pipeline movements, Vastar asserts that the calculations should include all legitimate costs of transportation. As a matter of fairness and non-discrimination, those costs should be those normally recognized for rate-setting purposes by the Federal Energy Regulatory Commission ("FERC" or "the Commission") and other regulatory agencies. The FERC, in setting allowable transportation rates for pipelines, determines the cost of service for a pipeline and allows rates that can be expected to cover that cost.

The two elements of the cost of transportation that I discuss are: (1) the appropriate determination of the cost of equity capital for a pipeline carrier, and (2) the appropriate calculation of the allowance for federal and state income taxes payable by the carrier. In each case, my verified statement describes both the general economic principles underlying the determination and the particular methodology by which the FERC calculates each of the two components of a pipeline's cost of service. My conclusion is that the methodology for dealing with these two cost components that is embedded in the current MMS regulations does not correspond to the FERC's approach (or to the approach of most state regulatory agencies) and is inconsistent with the applicable economic principles for properly measuring transportation costs.

**Rate of Return as a Cost Element**

The cost of capital is a significant element of a pipeline's cost of operating. In the unregulated world, a business normally charges prices that will cover its costs and provide a profit, a return to the owners of the business on their investment. In the regulated world, that profit is considered to be another cost – the cost of the capital provided by the owners. The cost in dollars is normally determined by multiplying a suitable rate of return by the investment. That rate of return is one found to be consistent with the cost of capital for alternative investments in companies having business and financial risk characteristics similar to those of the pipeline in question. The consistency is important in establishing a rate of return that will enable the pipeline to compete for capital in a free marketplace.

Investors face a wide variety of choices in investing their capital. If safety is of paramount importance they may prefer to buy U.S. Treasury securities, accepting an interest rate that is lower than those available, for example, on high quality corporate bonds that are a little more risky, because of some danger that the corporation will fail and the investor will not be paid the promised principal and interest. If that increase in risk is acceptable, the investor will choose the corporate bonds for their higher interest rate. If still higher risk is acceptable, the investor may choose lower quality corporate bonds offering yet higher interest rates, still relying on the contractual nature of the payment of principal and interest, but accepting a greater likelihood that the corporation will for some reason be unable to make the promised payments. Even greater risk, and even higher expectations of return, go with shares of stock. In this case there is no corporate promise of repayment of the investment or even of dividend payments. There is only the expectation that a well-managed corporation in a profitable industry will succeed in increasing its earnings and rewarding the investor with a rising stock price or dividends or both. The risk lies in the possibility that the corporation will perform poorly and the investor will be disappointed by a falling stock price and reduced dividends or none at all. Risk perceptions vary substantially across the range of stocks available for purchase, with some stocks regarded as not much riskier than low quality corporate bonds and others regarded as highly speculative. Correspondingly, the expectations of investors with respect to the rate of return, or profitability, vary substantially across that range.

Whatever the importance of safety may be to an investor, it is a fundamental economic principle that investors will knowingly choose a higher risk investment over a lower risk alternative only if the former can be expected to prove more profitable, that is, to offer a greater rate of return. In a free marketplace, like the United States stock market, share prices generally reflect the expectations of the investment community with respect to rates of return and the perceptions of that community with respect to risk. Hence, to establish what rate of return a pipeline must offer to investors in its shares of stock in order to persuade those investors to buy those shares and provide needed capital, it is necessary to establish the level of risk to the pipeline investors, and the rates of return they are expecting from other investments of comparable risk. The appropriate measure of the cost of equity capital to a particular enterprise is the expected rate of return on investments of comparable risk.

MMS policy, as expressed in 30 CFR §206.105 (b)(2)(v), specifies that the rate of return applied to the capital investment in the transportation pipeline and included in the cost of transportation shall be the interest rate published in Standard & Poor's (S&P's) Bond Guide for bonds with a BBB S&P rating. S&P rates industrial bonds from AAA (best quality) down to BBB (lowest quality of investment grade), and from BB (best quality of speculative grade) down to D (lowest quality of speculative grade). For oil pipelines with S&P bond ratings, the average rating is currently around BBB to A. (See Exhibit No. 2 to this verified statement, showing S&P and Moody's bond ratings. Moody's Investors Service provides bond ratings, and its rating of Baa corresponds to the S&P rating of BBB.)

However, pipelines are not financed entirely by debt, and regulatory agencies, including the FERC, recognize this. At present, the FERC recognizes five publicly traded oil pipeline companies as the best to use for comparison purposes in determining the cost of equity to a pipeline the shares of which are not traded in the marketplace. These are listed in Exhibit No. 2. The equity ratios in the capital structures of these companies are shown in the exhibit, and the average ratios of debt and equity are 54% and 46%, respectively. While the interest rate published by S&P for industrial BBB bonds may be a reasonable approximation of the current cost of debt for these oil pipelines, it falls far short of a reasonable approximation of the cost of equity. The procedure followed by the FERC, and to the best of my knowledge by most state regulatory agencies, is to determine an average overall cost of capital by weighting the cost of equity by the equity percentage of the total capital and by weighting the cost of debt by the debt percentage of the total, and computing the weighted average cost. That is, the weighted average cost is ((cost of equity x % equity) + (cost of debt x % debt)). The FERC practice is to use as the cost of debt not a published rate for a class of bonds (such as S&P BBB industrial bonds) but the actual cost of the pipeline's debt. The determination of the cost of equity is also specific to the particular pipeline but its determination is more complex.

There are several methodologies that can be used for the determination of the cost of equity, but the one most used by regulatory agencies, and relied on almost exclusively by the FERC, is the Discounted Cash Flow method. This method equates the price of a share in a company to the discounted stream of dividends the shareholder anticipates over the indefinite future. The discount rate is the rate of return expected by investors who put their money in such shares. It is this discount rate that is the cost of equity capital to the company. This is the rate that investors require if they are to buy the company's shares and so provide the company with needed equity capital. (The United States Supreme Court has stated that the tariff rates allowed a regulated utility by a regulatory agency must enable the utility to attract needed capital.) The most common formula by which the determination of the rate is determined is set out as $k = y + g$, where k is the cost of equity, y is the current dividend yield on the company's shares, and g is the growth rate in dividends expected by investors. This "market based" methodology is intended to rely on marketplace data to estimate the rate of return investors are actually requiring as the incentive to invest in the utility.

The FERC practice, when dealing with an oil pipeline, is to apply the equation above to a set of oil pipeline companies that are publicly traded (so that data are available as to the current dividend yields and expected growth rates). This calculation determines a cost of equity representative of the set of oil pipeline companies. From that cost, by comparing the risks of the subject pipeline to the risks in the set of publicly traded companies, the FERC will determine the cost of equity for the subject pipeline. Dividend yields are easily observable in the marketplace for publicly traded companies, because price data and dividend data are publicly reported. Investor growth expectations, on the other hand, are not directly observable and must be inferred. The data from which they are inferred are typically the published growth forecasts made by professional analysts or investment advisory services.

The Commission's method is actually quite conservative in that it relies not only on analysts' forecasts of earnings growth rates in determining the growth rate g, but averages analysts' forecast for the representative companies with long-term growth forecasts for Gross Domestic Product (GDP). The resulting k for pipelines is often lower than it would be if the FERC relied only on the analysts' growth forecasts as representative of investor expectations.

The most recently published FERC opinion discussing the determination of the cost of equity for an oil pipeline is Opinion No. 435, *SFPP, L.P.*, 86 FERC ¶ 61,022 (1999). In that decision the methodology to be applied in the case of an oil pipeline was set out, and the indicated cost of equity was 14.40%. An updated calculation, using the methodology set out in Opinion No. 435, yields a current cost of equity of 15.3%, as shown in Exhibit No. 2. (The FERC policy is generally to use the median cost, here 15.3%, unless the subject pipeline is of extremely high or low relative risk.) The 15.3% equity cost can be contrasted with the most recently published S&P BBB industrial yield (for November 1999) of 8.44 %.

The current MMS policy appears to assume that oil pipelines are financed entirely by debt carrying an interest rate equal to the average for S&P BBB industrial bonds. This is a quite unrealistic assumption. It may well have originated in a wish to keep the matter of cost of capital simple, but it results in seriously understating the true cost of capital. Market determined rates, whether unregulated or established by regulation, will normally include provision for all costs, including all capital costs. I believe that the MMS should recognize an appropriate cost of equity based on the FERC methodology.

**Income Tax Allowance as a Cost Element**

MMS policy as set out in 30 CFR §206.105 (b)(2)(iii) does not allow the inclusion of state or federal income taxes in the transportation allowance. Yet income taxes are an ordinary and necessary cost of doing business, as the FERC and, I believe, the state regulatory agencies all recognize. Rates must include an allowance for income tax if they are to cover the costs of doing business. Income tax must be paid by a pipeline corporation on its taxable income, and the practice of the FERC, and of state regulatory agencies I believe, is to include income tax in the cost of service which is the basis for rates set by the Commission and the state agencies.

The common procedure, followed by the FERC in the case of an incorporated pipeline, is to calculate the income tax, at corporate tax rates, corresponding to the dollar return on equity that is included in the cost of service. It is important to note that the "cost of equity" determined as described above, is always the <u>after-tax</u> cost, that is, the return to the investors after the income taxes of the corporation have been paid. Thus, if the dollars of return on equity for the pipeline operation are E, and the tax rate is T, then the allowance for income tax is $(E/(1\text{-}T) - E)$. Adding the return E to the tax allowance gives $E/(1\text{-}T)$ as the required earnings before tax and E as the earnings after tax. (The FERC departs from this approach only in the case of pipelines organized as partnerships with some partners that are not themselves corporations, where the allowance is reduced to the percentage of net income attributable to the corporate owners.)

The result of the procedure described above is to include in the cost of service both the justifiable return on equity and the associated income tax for the pipeline operation. I believe it is the appropriate procedure for the determination of cost of service for purposes of determining the transportation element of the royalty valuation determination.

If there is no allowance for income tax in the determination of the transportation cost, the result is an understatement of the true transportation cost. In effect, a portion of the appropriate equity return is taken away from the pipeline's investors and used to pay the corporation's income taxes. Assume, for example, that the investors' required rate of return (the cost of equity capital) is 15% on an investment base of $10,000. If the net taxable income of the corporation is $2,500 subject to federal and state income taxes at 40%, the taxes are $1,000, leaving $1,500, the correct return to the shareholders. If the company were allowed to earn net taxable income of only $1,500, rather than the $2,500, the income tax would be $600, leaving only $900 for the shareholders. The rate of return would then be only 9%, not the 15% cost of equity. Only by allowing the $1,000 income tax expense and bringing the net taxable income to $2,500, will the shareholders be able to earn their required 15%.

The result of failure to include an allowance for income tax expense is an understatement of the true transportation cost that is both unfair and discriminatory. It is unfair in that it simply understates the true transportation cost, something that I believe would not be permissible in the setting of tariffs by a regulatory agency. It is discriminatory in that transportation costs in the case of an arm's length pipeline whether regulated or unregulated, will normally cover the pipeline's income tax, while rates that are based on transportation costs excluding income taxes will not. The result is that investment in OCS pipelines is discouraged, contrary to the goal of developing offshore oil resources in a responsible manner.

To achieve fairness and avoid discrimination, the MMS should allow the inclusion of income taxes in the determination of transportation costs for purposes of establishing royalties.

# EDUCATION, TEACHING, RESEARCH AND PROFESSIONAL EXPERIENCE OF J. PETER WILLIAMSON

**Education**

University of Toronto, B.A. in 1952, Mathematics, Physics & Chemistry; Harvard Business School, MBA in 1954, DBA in 1961; Harvard Law School LL.B. in 1957.

**Teaching and Research**

From 1957 to 1961, Assistant Professor of Business Administration at the Harvard Business School. In 1961 joined the faculty of the Amos Tuck School of Business Administration at Dartmouth College as Associate Professor. On the Amos Tuck School faculty since 1961 and Professor since 1966 (except for one year on the faculty of the University of Toronto Law School). Currently the Laurence F. Whittemore Professor of Finance at the Amos Tuck School.

Teaching at the Amos Tuck School includes courses in corporation finance, financial institutions, investments and federal taxation. Research in these fields has led to a dozen or so books and monographs and to articles in the *Journal of Finance*, the *Financial Analysts Journal*, the *Journal of the Eastern Financial Association*, the *Journal of Bank Research*, the *Journal of Portfolio Management* and other professional journals.

**Consulting and Research**

Consulting activity, in addition to work for regulated utilities, has included valuations of banks and other businesses, advice on investment portfolios and specifically on investment expectations; and several publications have been specifically concerned with investment strategies, risk and likely rates of return. Author of four books that are largely concerned with this subject and a number of articles.

The book, *Performance Measurement and Investment Objectives for Educational Endowment Funds*, was published by the Common Fund in 1972. The book, *Funds for the Future*, published by the Twentieth Century Fund in 1975, consists chiefly of a discussion of investment of college and university endowment funds, including investment risk and expected rates of return. A revised and updated edition of this book, entitled *Funds for the Future: College Endowment Management for the 1990s*, was published by the Common Fund in 1993. The book, *Spending Policy for Educational Endowments*, co-authored with Richard Ennis of Ennis, Knupp & Gold, Inc., was published by the Common Fund in 1976. It deals with the relationship between spending plans and expectations of risk and return. Author of chapters in *The Handbook of Financial Markets and Institutions* (6th ed. 1986) and in *The Investment Manager's Handbook* (1980) entitled, respectively, "Performance Measurement" and "Educational Endowment Funds." Editor of, and author of two chapters in the *Investment Banking Handbook* published by John Wiley & Sons in 1988. Author of a chapter in the *Handbook of Modern Finance*, published by Warren Gorham Lamont in 1993.

Trustee of the Common Fund 1978-90, and Chairman of its Short-term Fund Committee. Participated as a trustee in the hiring, reviewing and replacement of over thirty investment managers who managed 5.5 billion dollars invested long-term. Worked more closely with three managers who managed another 4.5 billion dollar short-term funds of the Common Fund.

In 1966-67 and 1977-79, retained by the Canadian Government's Department of Consumer and Corporate Affairs to consider appropriate federal regulation of securities markets in Canada. One of four authors of *Proposals for a Securities Market Law for Canada* (1979) and the author of two working papers published as part of the *Proposals*: "Canadian Capital Markets" and "Canadian Financial Institutions."

**Regulatory Proceedings**

Has testified on behalf of a number of utilities and on behalf of several consumer representatives. Testified in 1980 on behalf of the Public Service Company of New Hampshire before the New Hampshire Board of Taxation in connection with the franchise tax paid by utilities in New Hampshire. Testified over the past 15 years in electric utility rate cases before the Vermont Public Service Board at the request of the Counsel for the Public, the Department of Public Service and the Public Service Board in connection with applications for rate increases filed by Green Mountain Power Corporation (Dockets 3642, 3758, 4418, 4503/4537, 4570, 4661, 4796, 4865, 5013 and 5125), Central Vermont Public Service Corporation (Dockets 3744, 3991, 4230, 4634 and 5030) and Vermont Electric Cooperative (Dockets 5009/5112 and 5630/5632), and on behalf of Green Mountain Power (Dockets 5282, 5370, 5428, and 5780).

Testified, at the request of the Vermont Public Service Board, on a proposed amendment by Central Vermont Public Service Corporation to its first mortgage bond indenture (Docket affiliates. It is undisputed that, from the Department's perspective, tariffs made in arm's-length transactions are appropriate transportation allowances because they are the lessee's "actual costs." If a producer purchases that same pipeline, however, the situation changes overnight. Under the current MMS rules and the new proposal, the new pipeline owner will no longer be allowed to take the same transportation allowance. This is both unfair and theoretically indefensible. Moreover, as Professor Jaffe observed, such discrimination may, in the long run, distort firms' decisions regarding affiliate transactions and vertical integration and would likely reduce investment in the development of Gulf resources.[35]

There is no difference to the Department whether a lessee transports oil at the same rate on its own pipeline or on one owned by a third party. As one Federal District Court has stated in the past: "[w]hen, instead of paying for the service to be done by someone else, the lessees performed that service for themselves and for the government, they were entitled to have the government royalty . . . bear its proportionate share of these costs which daily accrued against them."[36] Accordingly, the Department should bear its proportionate share of the costs of transporting oil to market and accept as valid the same tariffs that were paid the day before pipelines were purchased.

Continued acceptance of FERC tariffs is also consistent with the Department's own precedent. On several occasions, the Department has indicated that it is not appropriate to treat lessees differently for royalty purposes simply because of an affiliation with a pipeline. In Shell

[35] Jaffe Aff. at 6 7, 15.

[36] United States v. General Petroleum Corp., 73 F. Supp. 225, 257 (S.D. Ca. 1946), aff'd sub nom. Continental Oil v. United States, 184 F.2d 802 (9th Cir. 1950) (hereinafter "United States v. General Petroleum Corp.").

Western E & P, Inc.,[37] the Interior Board of Land Appeals considered whether a lessee affiliated with a pipeline should be treated the same as non-affiliated lessees, so that affiliated lessees could deduct the entire tariff as a transportation allowance instead of excluding the pipeline's income taxes from the tariff as MMS insisted. The Board concluded that "MMS's policy, while 'intended to preclude abuse and overcome audit burdens,' unfairly discriminates against lessees who are affiliates of pipeline operators."[38] The Board made it clear that:

> In the absence of some manifestation that affiliated companies are using their corporate relationship to defeat MMS royalty collection efforts, the general rule recognized in Getty Oil Co. applies.[39]

Companies do not formulate their corporate structure to defeat royalty obligations. Pipeline owners should be treated the same as any other lessee that ships on a pipeline and should be able to deduct all of their transportation costs from royalty payments.

In sum, FERC and state regulatory agency tariffs are based on real economic transportation costs, consistent with the Department's philosophy of looking to the market to

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[37] 112 IBLA 394 (1990) (hereinafter "SWEPI").

[38] Id. at 400.

[39] Id. (citing Getty Oil Co., 51 IBLA 47 (1980)). In Getty Oil Co., the Interior Board of Land Appeals refused to set aside an agreement between Getty and its wholly owned affiliate in the absence of impropriety. The Board cited Judge Learned Hand's opinion in United States v. Weissman, 219 F.2d 837 (2d Cir. 1955) in concluding: "It is true that there can be legal transactions between two corporations all of whose shares are owned by a single individual, and that the same obligations will arise out of them as would arise, had they been between either corporation and a third person." See also Mobil Producing Texas & New Mexico, Inc., 115 IBLA 164, 178 (1990) (denial of a transportation allowance for income taxes solely because it involves an affiliate of the pipeline operator is improper); Mobil Exploration and Production U.S., Inc., 148 IBLA 172, 185 (1999) (ALJ Hughes concurring "The issue presented is whether Mobil, as owners of the pipeline who also pay to use the pipeline, may property deduct payments to the pipeline. . . . I find no basis for disallowing Mobil use of the tariff as its transportation allowance when other parties . . . have been allowed to do so.").

make valuation determinations. Thus, tariffs should not be dismissed as unreasonable or unreliable representations of transportation costs and MMS should embrace them as appropriate transportation allowances where they exist. Moreover, MMS's presumption that FERC tariffs "exceed" actual costs is without basis, and MMS's failure to adequately justify its proposal is arbitrary and capricious.

### 2. In the Absence of Tariffs, MMS Should Accept Transportation Allowances for Non-Arm's-Length Transportation Based Upon Arm's-Length Transportation Contracts for Comparable Transportation Services

Even where tariffs are not in place, MMS should move toward more transparent, competitively defined costs and resist the urge to return to an era of unwieldy, prescriptive "actual cost" calculations. In keeping with long-standing Departmental policies, when establishing transportation allowances for non-arm's-length transactions, the Department should first consider arm's-length transportation contracts for comparable transportation services. Thus, in this case, the Department should look to several indicators: (1) transportation charges paid by third-party shippers on affiliated pipelines; (2) transportation charges paid by third-party shippers for transportation services comparable to that provided by affiliated pipelines; (3) transportation charges paid by a producer before it acquired interests in a pipeline; and (4) the tariffs maintained by the prior owner of the pipeline before the pipeline became affiliated.[40]

As the Department acknowledged when last revising its valuation rules, arm's-length transportation charges to third-party shippers are particularly relevant where there are several

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[40] See Jaffe Aff. at 10-13.

alternatives for shippers to use when transporting their oil,[41] especially where pipelines are underutilized, suggesting competitively low rates.

Indeed, the fundamental underpinning of all the Department's valuation regulations both past and present has been that the market should set value for royalty purposes.[42] If one looks back to the first disputes concerning the manner in which oil should be valued for royalty purposes and forward to more recent disputes, the one common thread is that the Department has said it wants to insure that the marketplace – not some arbitrary formula – determines royalty values. Examples are Continental Oil Co. v. United States, California v. Udall, and Marathon Oil Co. v. United States, in which the Department sought to value oil based on sales in the market even though the market was away from the lease.[43] More recently, the Department has alleged that companies have inappropriately paid oil royalties based on posted prices.[44] The

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[41] See discussion at p.23, infra, regarding the initial proposal for the current rule, in which MMS proposed that the non-arm's-length transportation allowance be based upon the volume-weighted average prices of arm's-length contracts.

[42] See 43 U.S.C. § 1331(o) (1986) (defining "fair market value" as average unit price at which a mineral was sold); see also Proposed Guideline and Request for Comments on How to Value Oil for Royalty Purposes From Federal and Indian Onshore and Offshore Leases, 47 Fed. Reg. 53,822, 53,822 (Nov. 11, 1982) ("The Royalty Management Program of MMS must assure that the [f]ederal [g]overnment and Indian lessors receive fair market value for their royalty oil.").

[43] Continental Oil Co. v. United States, 184 F.2d 802 (9th Cir. 1950); California Co. v. Udall, 296 F.2d 384 (D.C. Cir. 1961); Marathon Oil Co. v. United States, 604 F. Supp. 1375 (D. Alaska 1985), aff'd, 807 F.2d 759 (9th Cir. 1986), cert. denied, 480 U.S. 940 (1987).

[44] December 1999 Proposal, 64 Fed. Reg. at 73,821.

valuation methodology the Department has preferred in that context is arm's-length sales by the lessee's affiliates.[45]

The Department is not alone in its thinking. Oil and gas law treatises have long recognized that an arm's-length sale should be the first resort in royalty valuation.[46] At every point in establishing valuation standards, the Department has held firm to that principle.[47] That position has been true whether or not the production being valued is itself disposed of in an arm's-length transaction.[48] In fact, the Interior Board of Land Appeals has noted that "[i]f a transaction is not at arm's length, some other manifestation that the price is nonetheless an accurate portrayal of the article's worth is required. It must be a price which independent buyers

[45] Id. ("This rulemaking proposes to amend the current regulations by eliminating posted prices as a measure of value and relying instead on *arm's-length sales prices* and spot market prices as market value indicators.") (emphasis added).

[46] See e.g., 3A W.L. Summers, The Law of Oil and Gas § 590 at 129 (1958 perm. ed.); 3 Williams and Meyers, Oil and Gas Law §§ 650, 650.2 (1993). Numerous other government entities recognize the value in using arm's-length transactions for valuation purposes. For the purpose of calculating U.S. taxable income, for instance, the Internal Revenue Service requires that the transfer prices between affiliated multinational companies be based on arm's-length transactions for similar goods or services. See Jaffe Aff. at 9-10.

[47] See Shell Oil Co., 70 I.D. 393, 394 (1963) (citing the prior rule, 30 C.F.R. § 250.64, which directed the Department to determine oil value with reference to "the highest price paid for . . . production of like quality in the same field or area" as well as to "the price received by the lessee" and "posted prices"); 30 C.F.R. § 206.102(a) (current rule) (relying on arm's-length contract price to determine oil valuation); December 1999 Proposal, 64 Fed. Reg. at 73,821 (proposing to value oil based on "arm's-length sales prices").

[48] See Shell Oil Co., 70 I.D. at 394 (1963) (citing the prior rule, 30 C.F.R. § 250.64, which directed the Department to determine oil value with reference to "the highest price paid for . . . production of like quality in the same field or area" as well as to "the price received by the lessee" and "posted prices" for non-arm's length contracts as well as arm's-length contracts). The current rule, 30 C.F.R. § 206.102(c), relies to a large degree on arm's-length contract prices to determine the value of oil sold under non-arm's-length contracts. The December 1999 Proposal seeks to value non-arm's length oil sales based on arm's-length prices or spot prices. See 64 Fed. Reg. at 73,829-30.

in arm's length transactions would be willing to pay."[49] It is not surprising then that this thinking was transferred to establishing transportation allowances for non-arm's-length contracts during the rulemaking process that led to the current regulations.[50]

In that process, the Department initially proposed using volume-weighted average prices of arm's-length contracts as an exception to the so-called "actual cost" calculation for non-arm's-length transportation allowances. However, the final regulation dropped this provision with only the most cursory statement.[51] In the end, the final regulation continued to provide an exception to calculating "actual costs" for non-arm's-length transportation allowances using FERC or state regulatory tariffs measured against arm's-length contracts.[52]

In those instances where arm's-length contracts have not existed or have simply been too difficult for lessees to obtain easily before paying royalties, the Department has shown a willingness to resort to independent, more transparent market-based measures of arm's-length

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[49] Getty Oil Co., 51 IBLA 47 (1980) (citing Acme Mfg. Co. v. United States, 492 F.2d 515, 520 (5th Cir. 1974)). Although the IBLA cited the case name as Acme Mfg. Co. v. United States, the name of the case appearing at 492 F.2d 515 is Creme Mfg. Co. v. United States. The misnomer is likely an unintended error on the Board's part, as Creme appears to support the assertion for which Acme was cited by the IBLA.

[50] See Further Notice of Proposed Rulemaking, Revision of Oil Product Valuation Regulations and Related Topics, 52 Fed. Reg. 30,826, 30,849 (proposed Aug. 17, 1987) ("August 1987 Proposal for the Current Rule").

[51] In support of the current rule, MMS simply declared it to be "in the best interests of the [g]overnment, [s]tates and Indians to base oil transportation allowances on actual, reasonable costs plus return on investment." Final Rule, Revision of Oil Product Valuation Regulations and Related Topics, 53 Fed. Reg. 1184, 1211 (Jan. 15, 1988) (codified at 30 C.F.R. § 206.105) (hereinafter, the "1988 Final Rule"). This terse, conclusory explanation did not meet administrative law requirements that an "agency must examine the relevant data and articulate a satisfactory explanation for its action including a 'rational connection between the facts found and the choice made.'" Motor Vehicle Mfrs. Ass'n v. State Farm Mut., 463 U.S. 29, 43 (1983) (quoting Burlington Truck Lines, Inc. v. United States, 371 U.S. 156, 168 (1962)).

[52] 30 C.F.R. § 206.105(b)(5).

prices (e.g., spot prices or New York Mercantile Exchange ("NYMEX") futures prices) rather than devising some more complicated formula.[53] The same should be true for valuing transportation allowances.

Similarly, in the past several years, the FERC has moved steadily away from more prescriptive ratemaking practices in favor of indexing or market-based methodologies for pipeline rates. The FERC has explained the numerous benefits associated with these methods,[54] noting, for example, that a system in which base rates are periodically indexed up or down based on an inflation measure is efficient, simple and stable, and it provides appropriate economic incentives to pipeline operators. "Under indexing, pipelines adjust rates to just and reasonable levels for inflation-driven cost changes without the need of strict regulatory review of the pipeline's individual cost of service, thus saving regulatory manpower, time and expense."[55] The indexing scheme supports rate stability by protecting shippers from rate increases greater than

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[53] See, e.g., Final Rule, Amendments to Gas Valuation Regulations for Indian Leases, 64 Fed. Reg. 43,506 (Aug. 10, 1999) (adopting spot prices for valuing gas on Indian lands); January 1997 Proposal, 62 Fed. Reg. 3742 (proposing to value oil from federal leases based on crude oil futures prices on the NYMEX); Notice of Proposed Rulemaking, Establishing Oil Value for Royalty Due on Indian Leases, 63 Fed. Reg. 7089 (proposed Feb. 12, 1998) (proposing to use NYMEX futures prices to value oil from Indian leases); December 1999 Proposal, 64 Fed. Reg. at 73,829-30 (seeking to value non-arm's length federal oil sales based on arm's-length prices or spot prices); Notice of Proposed Rulemaking, Amendments to Gas Valuation Regulations for Federal Leases, 60 Fed. Reg. 56,007 (proposed Nov. 11, 1995) (proposing index prices for valuing federal gas).

[54] Final Rule, Revisions to Oil Pipeline Regulations Pursuant to the Energy Policy Act of 1992, 58 Fed. Reg. 58,753, FERC Statutes and Regulations, Regulations Preambles, 1991-1996 ¶ 30,985, at 30,948 (1993); Final Rule, Market-Based Ratemaking for Oil Pipelines, 59 Fed. Reg. 59,148, FERC Statutes and Regulations, Regulations Preambles, 1991-1996 ¶ 31,007, at 31,179-80 (1994).

[55] FERC Statutes and Regulations, Regulations Preambles, at 30,948.

the inflation rate.[56] Further, indexing is a form of incentive regulation that supports productive efficiency better than traditional cost-of-service regulation.[57]

Likewise, the FERC has encouraged the use of market-based rates.[58] Pipelines that demonstrate a lack of market power in specific origin and destination areas can charge market-based rates to and from those locations, rather than rates strictly tied to costs.[59] Such market-based rates are the hallmark of the lighter-handed form of rate regulation mandated by Title VIII of the Energy Policy Act of 1992.[60] Moreover, the FERC has declared that it is "confident that the information provided to it by the procedural requirements [for market-based rates] will permit the Commission to make informed decisions about market power and prevent the possibility of abuses of market power."[61]

In defining transportation allowances, the Department should carefully consider the steps it has already taken away from prescriptive formulas and take close note of the example set by the FERC – an agency steeped in traditional cost-of-service ratemaking – and move toward more transparent, competitively-defined measures. The alternative is a return to an era of unwieldy "actual cost" calculations, which is both unnecessary and unreflective of real-world business transactions. Therefore, Vastar recommends that the MMS not hastily disregard using arm's-

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[56] Id. at 30,948-49.

[57] Id. at 30,948.

[58] Final Rule, Market-Based Ratemaking for Oil Pipelines, 59 Fed. Reg. 59,148, FERC Statutes and Regulations, Regulations Preambles, 1991-1996 ¶ 31,007 (1994).

[59] FERC Statutes and Regulations, Regulations Preambles, at 31,179.

[60] 42 U.S.C. § 7172 (Supp. 1993); FERC Statutes and Regulations, Regulations Preambles, at 31,179.

[61] FERC Statutes and Regulations, Regulations Preambles, at 31,180.

length transportation transactions in determining non-arm's-length transportation allowances. As noted above, arm's-length transactions are both historically and economically the most acceptable basis for measuring the validity of non-arm's-length transactions. Those facts, in combination with the relative simplicity of employing the methodology, strongly support MMS's adopting this methodology for calculating non-arm's-length transportation allowances or, at the very least, using this methodology to verify the reasonableness of such transportation allowances.

### 3. In Any Event, The Department Should Allow Deductions Reflecting the Real Economic Cost of Transportation Service

If the Department refuses to accept arm's-length transportation charges or FERC or state regulatory agency tariffs as adequate proxies for determining non arm's-length transportation allowances, it must allow *all* reasonable actual transportation costs, rather than an arbitrary amount that maximizes royalty payments. Although the December 1999 Proposal would permit lessees that do not own pipelines to deduct all of their actual transportation costs, the same is not true for lessees that own pipelines used to transport their own production, as to whom MMS proposes to continue to limit what may be classified as "actual costs" for non-arm's-length transportation. What is not adequately recognized in the proposal is, among other items, the actual cost associated with income taxes, pipeline loss allowance, and the allocation of corporate overhead. And, as discussed above, the proposal sets the rate of return at an arbitrary and unreasonably low level.[62] As Professor Jaffe explains, however, this proposal does not reflect

[62] The Department has indicated in the past that certain exclusions or limitations placed by MMS on transportation allowances may be unreasonable and arbitrary. For example, in Mobil Producing Texas & New Mexico, Inc., the Interior Board of Land Appeals found that MMS's prior policy of capping operating costs at 10 percent of the undepreciated initial or adjusted investment cost when calculating transportation allowances might "not reasonably

(Continued ...)

the real economic cost of service. Moreover, "[t]his approach suffers . . . from a number of well-known shortcomings, including high administrative burden, reduced efficiency incentives, lack of sufficient data, and an inability to respond appropriately to changes in underlying market conditions in a timely manner."[63]

If the Department insists upon calculating its own transportation rates for non-arm's-length transactions, it should recognize the precedents set by ratemaking agencies for decades as the proper cost analysis. MMS has said that it does not have to recognize FERC precedents because the two agencies have different missions.[64] Those differences, however, confirm that the FERC's precedents should be recognized. The FERC has been entrusted by the Congress with the role of setting "just and reasonable" rates for oil pipelines under the Interstate Commerce Act.[65] MMS has no such mandate or expertise in determining costs of transportation for oil pipelines and should leave this work to the experts at the FERC.[66]

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represent value transportation adds to the product and its application defeats the reason for giving a transportation allowance." 115 IBLA at 172. Although there was not enough information to reach a conclusion about the reasonableness of the cap in that instance, the Department made it clear that unreasonable and arbitrary limitations on transportation allowances would not be permitted.

[63] Jaffe Aff. at 13; see also Jaffe Aff. at 5-7.

[64] August 1987 Proposal for the Current Rule, 52 Fed. Reg. at 30,851 ("MMS does not believe that the FERC's obligations in developing tariffs and those of MMS in developing transportation allowances are sufficiently similar to warrant use of similar procedures.").

[65] See 49 U.S.C. § 60502 (1997); see also Association of Oil Pipe Lines v. FERC, 83 F.3d 1424, 1428-29 (D.C. Cir. 1996).

[66] In 1981, the Interior Board of Land Appeals considered whether to apply the ICC's (the predecessor agency to the FERC) oil pipeline rate-of-return standards, which had been set in the 1940's, to transportation allowances. Shell Oil Co., 88 I.D. 1 (1981). The IBLA ultimately decided not to adopt the ICC standards advocated – not because they were irrelevant – but because they were too old. Id. at 5-6 (stating "[t]o the extent that economic conditions facing the oil pipeline industry have changed since 1948 . . . the conclusions of the ICC in its earlier cases

(Continued . . .)

If MMS nevertheless concludes that a detailed cost of service must be calculated, then both law and fairness require that all of the relevant and reasonable costs incurred in providing that service should be included in the transportation allowance.

The proposal falls short of that standard in several important respects. As described below, the proposed regulations either expressly or implicitly understate non-arm's-length transportation costs as compared to those that would be recognized by the FERC and other regulatory agencies under traditional cost of service principles, in such areas as rate of return, income taxes and pipeline loss allowance. In addition, the proposed rule regarding the allocation of corporate overhead is sufficiently uncertain in terms of its application that, unless it is clarified, it may result in the unfair exclusion of real costs incurred in connection with the transportation activity.

The effect of these various defects, if uncorrected, would be to fail to recognize all legitimate transportation-related costs and, in turn, to overstate significantly the royalty properly owed to MMS. In addition to the rate of return, which is discussed above in Parts I.B and I.C., these excluded or understated costs are:

a) Income Taxes

Although it has been expressly rejected as "untenable," the MMS rule excluding federal and state income taxes as a permissible transportation allowance component for non-arm's-

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as to appropriate rates of return are equally as much artifacts of a bygone era"). The Board concluded "[i]t is evident from our investigation that a fair rate of return depends greatly on the economic conditions and other circumstances of the case at the time involved." Id. at 6; but see Conoco, Inc., 109 IBLA 89, 95 (1989).

length transactions continues to be the prevailing MMS policy. That policy is unsustainable both as a matter of economics and of essential fairness.

The current regulation states, in the context of allowing inclusion of certain types of overhead amounts in the transportation cost, that "State and Federal income taxes and severance taxes and other fees, including royalties, are not allowable expenses."[67] Such taxes and fees are allowable, however, if included in the actual cost of third-party transactions.[68] The sole factor determinative of whether taxes and fees may be included in the transportation allowance is whether the transportation service is or is not being provided by an affiliate.

The stated basis for the rule is the MMS characterization of income taxes as "an apportionment of profit rather than a valid operating expense."[69] As a matter of logic, that view would be expected to result in a return component that reflects the obligation to pay income taxes out of the company's profit (i.e., a "pre-tax" return). However, the agency also specifically refused to establish a rate of return that accounts for income tax liability.[70] The rule was purportedly grounded on the perceived potential for abuse in tax attribution between affiliated entities.[71] No real-world examples of such abuse were provided, nor was there any explanation

[67] 30 C.F.R. § 206.105(b)(2)(iii).

[68] Id. at § 206.105(a)(1).

[69] August 1987 Proposal for the Current Rule, 52 Fed. Reg. at 30,850.

[70] 1988 Final Rule, 53 Fed. Reg. at 1212.

[71] SWEPI, 112 IBLA at 399-400 (rejecting the MMS policy "[i]n the absence of some manifestation that affiliated companies are using their corporate relationship to defeat MMS royalty collection efforts").

as to why the absolute exclusion of a tax allowance for affiliated movements was adopted rather than a remedy more directly tailored to the agency's specific concern.[72]

The MMS policy of permitting inclusion of income taxes as an allowable transportation cost for third-party movements but not for movements on an affiliated pipeline was the subject of an appeal from a decision of the Director of MMS, which had affirmed an order of the Royalty Valuation and Standards Division disallowing federal and state income taxes as transportation costs for purposes of calculating royalties owed to MMS. There, a lessee with a non-arm's length transportation contract sought to use its FERC tariff as a basis for calculating its transportation allowance. MMS accepted the use of the FERC tariff, but demanded that federal and state income taxes be eliminated in computing the allowance. MMS explained that its policy regarding taxes in non-arm's-length situations is "premised on the impossibility of accurately allocating the correct tax burden to the pipeline, as well as the other activities of the pipeline/producer . . . . The MMS policy is a reasonable measure intended to eliminate the potential for abuse that could result from expense manipulation between pipelines and production facilities not wholly independent of each other."[73]

The Interior Board of Land Appeals rejected this disparity in the treatment of arm's length and non-arm's-length situations. In SWEPI, the IBLA deemed this rationale to be unsound, observing that:

> MMS appears untroubled by the general concept of allowing a lessee to include income taxes paid by a pipeline as an element of transportation costs, since it allows a deduction if there is a published tariff for a common carrier

[72] See Rio Grande Pipeline Co. v. FERC, 178 F.3d 533, 542-43 (D.C. Cir. 1999) (rejecting FERC per se cost exclusion because of failure to consider less extreme and more flexible alternatives).

[73] See SWEPI, 112 IBLA at 399.

> which includes income taxes as transportation costs. When there is no published tariff, as in the instant case, only lessees who are affiliates of pipeline owners are not allowed to deduct income taxes as transportation costs. . . . MMS' application of the [rule against allowing income taxes] only when the lessee is an affiliate of the pipeline owner is untenable.[74]

In sum, income taxes are a very real and substantial cost of providing transportation service from the OCS. The MMS proposal to continue excluding taxes from the allowable transportation cost is both unfair and without a rational basis, and should not be applied to lessees in the event a cost of service calculation is required for non-arm's-length pipeline movements.

b) Pipeline Loss Allowance

The December 1999 Proposal expressly prohibits deductions for "payments (either volumetric or for value) for actual or theoretical losses" under a non-arm's-length transportation contract.[75] MMS thus excludes from the transportation allowance a significant element of the cost of providing pipeline service from OCS leases. The costs of pipeline losses are real, demonstrable and among the category of expenses that are traditionally – and appropriately – allowed in determining overall transportation costs. MMS does not prohibit such costs in the transportation allowance for third-party movements, and there is no rational basis for excluding them solely in the case of pipeline movements for affiliates.

Since oil losses can rarely be ascribed to an individual shipper's volumes, the purpose of the Pipeline Loss Allowance ("PLA") is to spread the cost of the normal amount of pipeline loss equitably among all shippers. That can be done either in the form of a monetary charge that is

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[74] Id.

[75] December 1999 Proposal, 64 Fed. Reg. at 73,848 (proposed § 206.118).

included in the pipeline tariff, or by calculating the pipeline's obligation to deliver as a percentage of the oil tendered. Thus, FERC and Texas Railroad Commission pipeline tariffs typically provide that a pipeline may deduct a percentage of volumes for evaporation and loss during transportation, with the net balance to be the quantity deliverable by the pipeline.[76]

Notwithstanding this consistent acknowledgement that pipeline losses are among the core group of pipeline costs that are conventionally and properly passed through to shippers (and thus appropriately included in a lessee's transportation allowance), the MMS regulations exclude the costs of pipeline loss in the case of transportation for affiliates. To Vastar's knowledge, the only justification for that rule is "the difficulty of demonstrating that losses are valid and not the result of meter error or other difficult to measure causes."[77] That, of course, is no more true in the case of affiliated pipeline movements than for third-party movements. In each case, the actual experience of the pipeline can be tested to assure that the PLA is fair and reasonable; the "difficulty" cited by the MMS is no greater if the shipper is a pipeline affiliate than if it is not.

Pipeline losses, in short, should be included in the calculation of the transportation allowance whether or not the transportation is provided by an affiliate.

c) Allocation of Corporate Overhead

The December 1999 Proposal clearly provides that overhead that is directly attributable and allocable to the operation and maintenance of the transportation system may be taken as an

[76] See, e.g., 16 TAC § 3.66(9)(C) (1999), Texas Railroad Commission, Oil and Gas Rule 71, Pipeline Tariffs, Section 9(A), included in Vastar Pipeline TRC Tariff No. 1, section 9(A); ARCO Pipe Line Co., 52 FERC (CCH) ¶ 61,055, at 61,245 (1990).

[77] August 1987 Proposal for the Current Rule, 52 Fed. Reg. at 30,853.

allowable expense.[78] However, the proposed regulations do not specify how the allocation is to be made, the type of documentation that is required to sustain the expense, or the degree of estimation that is permissible. This has resulted in a degree of uncertainty that has worked to the significant disadvantage of lessees such as Vastar. Vastar submits that an allocation of overhead based on a reasonable formula of the type that has been accepted by the FERC should be accepted by the MMS for purposes of the valuation determination, so long as the input data applied to the formula is itself reliable, reasonable and available for review and audit by the MMS.

The two overhead allocation methods most commonly used by the FERC are generally known as the Massachusetts formula and the Kansas-Nebraska (or KN) formula. The Massachusetts formula, which has its origins in the decisions in Midwestern Gas Transmission Co.[79] and Distrigas of Massachusetts Corp.,[80] "allocat[es] parent overhead costs to a subsidiary on the basis of the average of the ratios that the subsidiary's labor costs, gross plant, and gross revenues have to the parent."[81] Each of those items typically is readily available both to the company and to the agency with oversight authority, and where one is not, or for any reason one of the factors is not suited to the task, alternatives may be proposed.[82] The other commonly used

[78] December 1999 Proposal, 64 Fed. Reg. at 73,847 (proposed § 206.111(f)).

[79] 32 F.P.C. 993 (1964), modified, 44 F.P.C. 721 (1970).

[80] 41 FERC (CCH) ¶ 61,205 (1987).

[81] Id. at 61,554; see also, e.g., Mojave Pipeline Co., 81 FERC (CCH) ¶ 61,150, at 61,176-78 (1998).

[82] See, e.g., SFPP, L.P., 86 FERC (CCH) ¶ 61,022, at 61,083 (1999) (company proposed modified Massachusetts formula in which barrel miles would be used as a proxy for revenue where revenue was itself the ultimate issue in the case).

formula – KN, derived from Kansas-Nebraska Natural Gas Co.,[83] – is a two-factor approach, in which total direct labor costs and capital investment (or gross plant) are used.[84] The KN formula is typically used to allocate overhead costs as among different functions within a company (such as among the various pipeline entities within VPL). Under each formula, the intent is to find a fair and objective measurement of the principal factors that give rise to the overhead costs being incurred – that is, some mix of property, labor and revenue.

Overhead amounts of the type involved here are routinely included in the body of costs that a pipeline includes in calculating its rates. There is simply no sustainable policy basis for treating those costs differently depending on whether the transportation service is being provided to an affiliate or a third party. If the overhead amounts are properly determined and allocated to the relevant assets, there is no less reason to include them in the transportation allowance for affiliated movements than for third-party movements.

## III. Conclusion

It is true that under the terms of federal leases, the Department is entitled to share in the "amount or value" of a Federal lessee's oil or gas production.[85] However, that entitlement in no way extends to sharing in the "amount or value" of a Federal lessee's other lines of business. As Professor Jaffe notes, "[s]etting a transportation allowance below the market price for transportation would be economically equivalent to a confiscation by MMS of part of the

[83] 53 F.P.C. 1691, 1721-22 (1975), aff'd, Kansas-Nebraska Natural Gas Co. v. FPC, 534 F.2d 227 (10th Cir. 1976)

[84] See, e.g., Questar Pipeline Co., 74 FERC (CCH) ¶ 61,126, at 61,455 (1996); Panhandle Eastern Pipe Line Co., 46 FERC (CCH) ¶ 61,183, at 61,615 (1989).

[85] See 43 U.S.C. § 1337(a)(1)(A).

economic returns associated with transportation investments, or equivalently, a unilateral increase in the royalty rate itself."[86] The Department may not overstate royalty obligations by arbitrarily excluding categories of significant actual costs from the transportation allowance or refusing to accept tariffs or comparable arm's-length transactions as representative of actual costs for non-arm's-length transportation. Instead, the Department must provide for a fair royalty while encouraging development of federally-owned natural resources. To do otherwise would be inconsistent with the intent of Congress.

Respectfully submitted,

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[86] Jaffe Aff. at 6.